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Certification Testing at the National Wind Technology Center

Arlinda A. Huskey
Harold F. Link

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Arlinda Huskey
Hal Link
National Wind Technology Center
National Renewable Energy Laboratory
Golden, Colorado

Abstract

The International Electrotechnical Commission is developing a new standard that defines power performance measurement techniques. The standard will provide the basis for international recognition of a wind turbine's performance primarily for certification, but also for qualification for tax and investment incentives, and for contracts. According to the standard, the power performance characteristics are defined by a measured power curve and by projections of annual energy production for a range of wind conditions.

The National Wind Technology Center (NWTC) has adopted these power performance measurement techniques. This paper reviews the results of the NWTC's first test conducted under the new protocol on the Atlantic Orient Corporation's AOC 15/50 wind turbine at the NWTC. The test required collecting sufficient data to establish a statistically significant database over a range of wind speeds and conditions. From the data, the power curve was calculated. Then the results from a site calibration procedure determined the flow distortion between winds measured at the turbine location and those measured at the meteorological tower. Finally, this paper discusses the uncertainty analysis that was performed in accordance with the standard. Use of these procedures resulted in the definition of the AOC 15/50's power curve within about 3 kW.

Introduction

The International Electrotechnical Commission (IEC) drafted IEC 1400-12 -- Power Performance Measurement Techniques for Wind Turbine Generator Systems[1] (herein referred to as "the Standard") to provide guidance in the measurement, analysis, and reporting of power performance characteristics of a wind turbine generator system. The Standard will apply to the testing of wind-turbine generator systems of all sizes and types connected to the electrical power network. The Standard is meant to provide procedures that give accurate, repeatable results.

In addition to the Power Performance Standard, the IEC has drafted IEC 1400-10 -- Acoustic Noise Measurement Techniques[2]. The National Wind Technology Center (NWTC) has the capability to execute these standard procedures. Also, there are several other IEC standards in the drafting stage including fatigue loads, power quality, and blade testing. The NWTC will also develop the capability to test in accordance with these standards as they approach final acceptance.

Background

The AOC 15/50 test turbine is located at Site 1.1 of the NWTC south of Boulder, Colorado as shown in Figure 1. The turbine site is 1849 m (6065 ft) above sea level so air density is approximately 80% of sea level density. The surrounding terrain is fairly complex and covered with sparse vegetation.

The AOC 15/50 wind turbine is a stall regulated, constant pitch, constant speed, horizontal axis turbine with a 15 m rotor. Although the AOC 15/50 is rated at 50 kW, it has a peak power output close to 65 kW. It was developed by the Atlantic Orient Corporation of Norwich, VT with support from the U.S. Department of Energy's Turbine Development Program.

Tests involved two series of measurements for power curve determination and flow distortion correction factors. These are discussed in the following sections.

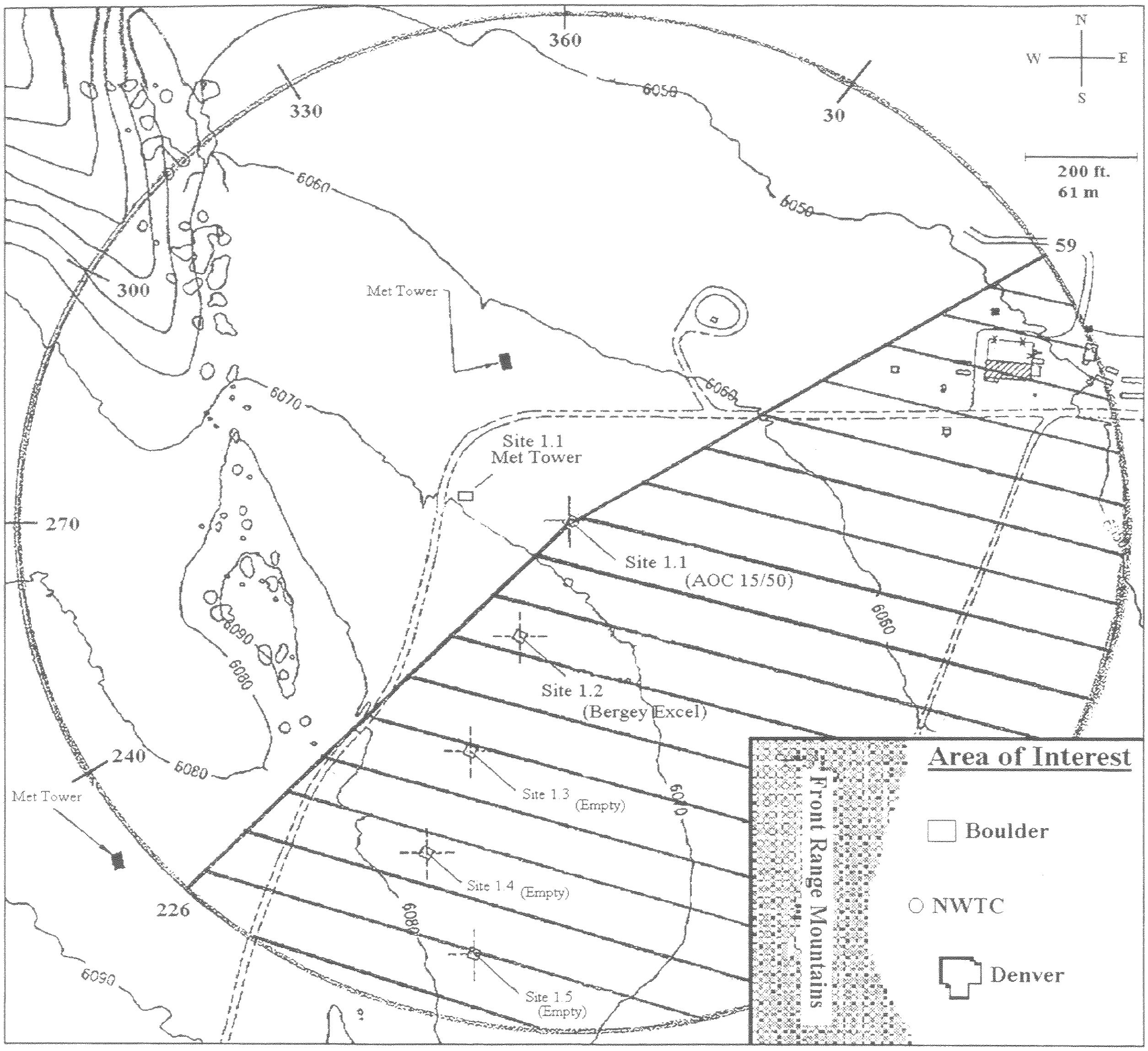

Figure 1 - Site 1.1 AOC 15/50 at the NWTC included with neighboring wind turbines and obstacles

Site Calibration

Site calibration is the determination of the flow-distortion correction factors due to the test site's terrain. Hills and other variations in the terrain can cause errors in wind speed measurements because winds are diverted or slowed before reaching the wind speed sensor. The Standard requires that some assessment of terrain effects must be made whenever the test site varies significantly from a specified "flatness." This assessment can be made through computer modeling of the site or through measurements. For this test, the measurement method was used.

The Standard does not rigorously define the measurement or analysis procedures used to determine terrain effects. The procedure described here is an NWTC modification of methods used by European test engineers[3]

Preferably, site calibration measurements are conducted prior to the installation of the test turbine. A temporary meteorological tower is installed at the position where the turbine is normally installed. Using a temporary meteorological tower eliminates the uncertainty associated with flow distortion caused by a turbine nacelle and blades if the anemometer is mounted on the test turbine. Wind speed is measured

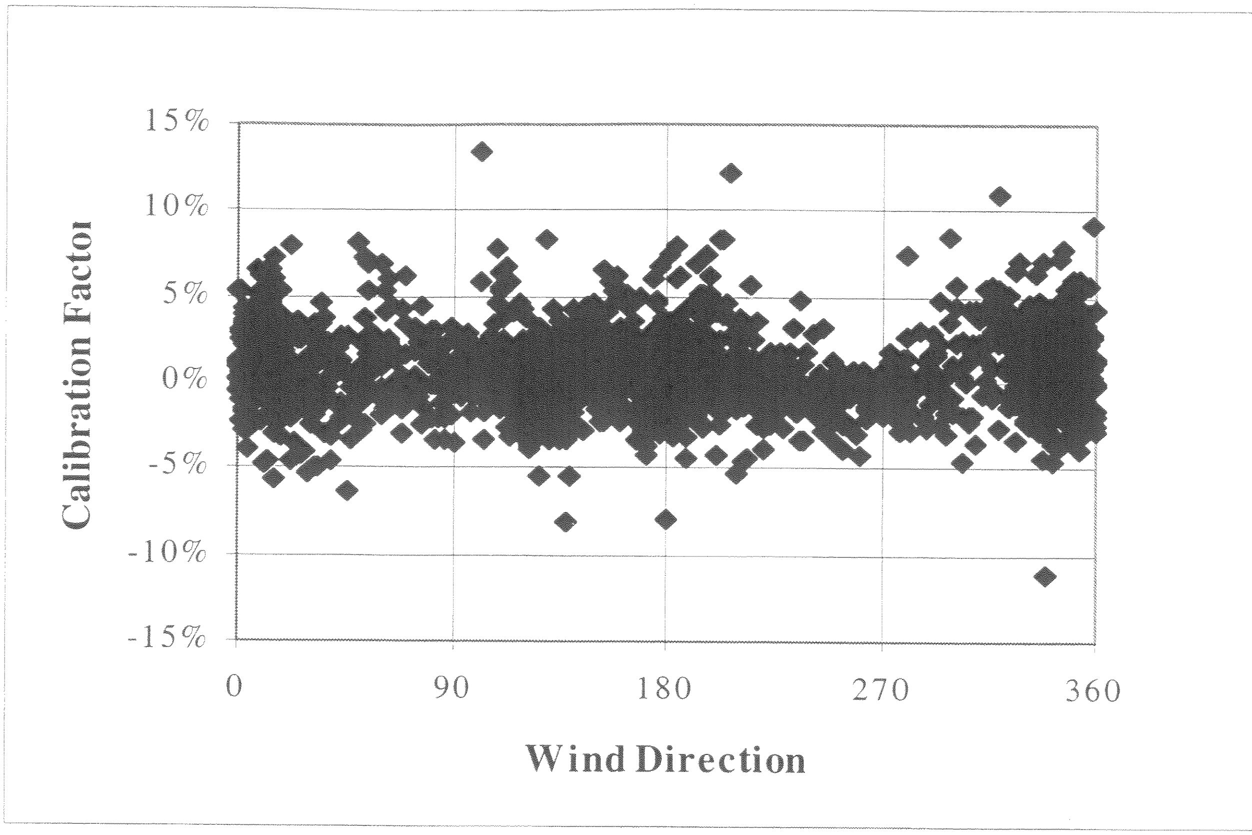

Figure 2 - Correction factor from the AOC 15/50 site calibration

at hub height on both of the meteorological towers and wind direction is measured at the permanent meteorological tower. Measurements were recorded at a one-hertz sample rate by a Campbell Scientific, Inc. data logger, Model 21X. The data logger provides some real-time data analysis capabilities including determination of mean, minimum, maximum, and standard deviation of each of the signals for each 10-min data set

In post-processing analysis, the first step is to eliminate data with wind speeds below 5 m/s. At low wind speeds, the variability in wind direction and reduced accuracy in anemometry resulted in a poor correlation. Also, turbine cut-in speeds are typically higher than 5 m/s.

Next the ratio of wind speeds for each 10-min set is plotted as a function of wind direction, as shown in Figure 2. This scatter plot shows how strongly the wind speed ratio changes with direction and helps to determine appropriate wind direction sectors for binning. For this site, Figure 2 suggests that the maximum sector size permitted by the Standard, 30 degrees, is appropriate.

Once the sectors are defined, the data are binned by wind direction. A linear regression is fit to the data for each sector as shown in Figure 3. Assumptions of a linear fit and zero intercept have been satisfactory for all data sets analyzed to date. These assumptions allow use of a single "correction factor," the slope of the regression line.

Another important factor in site calibration testing is ensuring that a sufficient quantity of data have been obtained. The present draft of the Standard requires only 3 hours of 5 to 10 m/s data for each sector. One way to assess whether sufficient data have been obtained is to plot the correction factor as a function of the hours of data for each sector to look for convergence. Figure 4 shows that the 59 hours of data obtained in the sector from 330° to 360° have yielded a stable correction factor of 0.09%. In contrast, the 12 hours of data in the sector from 270° to 300° are not sufficient.

When sufficient data are obtained in all the sectors used to measure turbine performance, we will apply the correction factors for each sector to the 10-minute data

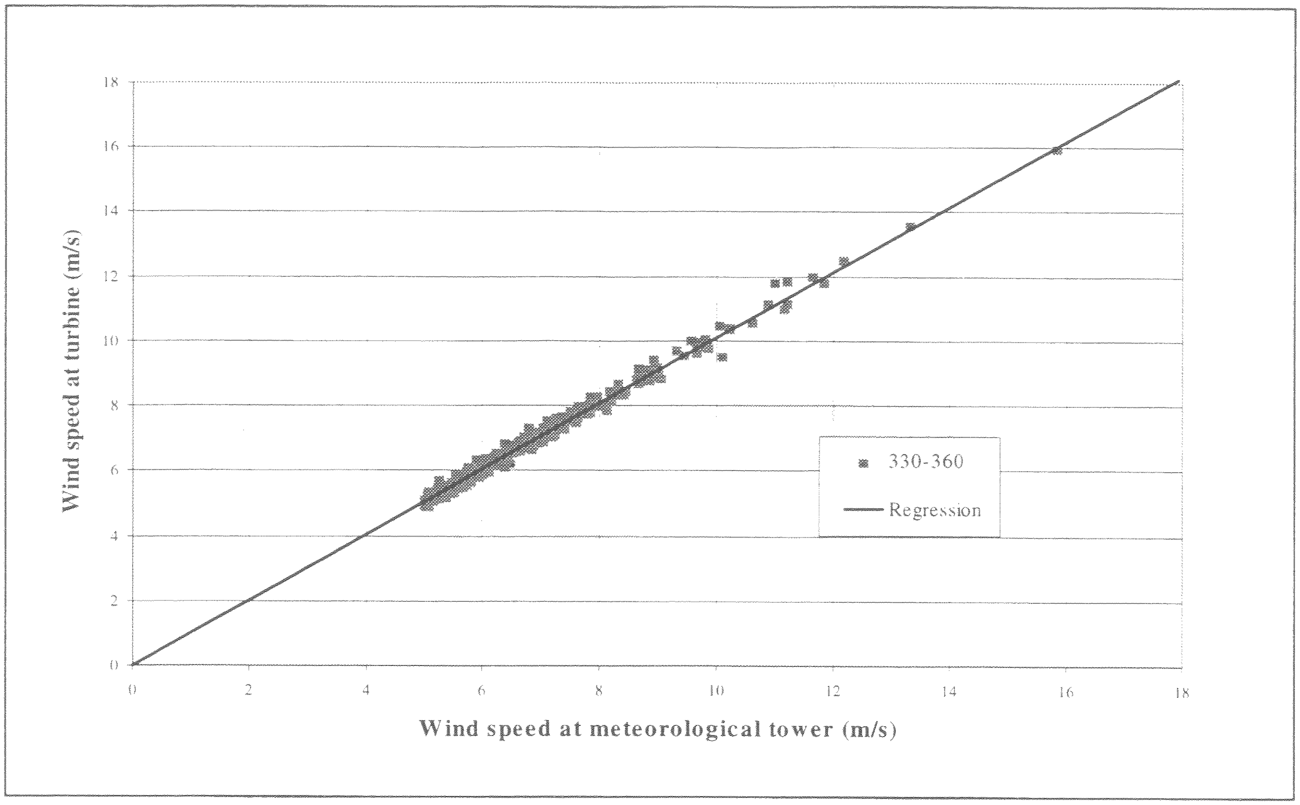

Figure 3 - Comparison of wind speed between the meteorological tower and turbine

sets obtained during turbine testing and recalculate the power curve and annual energy production. In the meantime, correction factors of unity were assumed.

Power Curve

For power curve determination, time series data were collected on the Advanced Data Acquisition System (ADAS) from November 1995 through December 1995. The ADAS is a data acquisition system designed for taking measurements from wind turbines and meteorological towers. The following measurements were recorded at 0.5 Hz samples from the meteorological tower: wind speed (m/s), wind direction (degrees relative to true north), power output from the turbine (kW), air temperature (°C), and air pressure (kPa). The anemometer was at hub height (25 m) as required by the Standard. Table 1 describes the instrumentation used for the power curve determination.

Table 1 - Instrumentation used for power curve determination

Instrument	Manufacturer	Model
anemometer	Met One Instruments	WS-201
wind direction sensor	Met One Instruments	WD-201
temperature probe	Met One Instruments	T-200
pressure sensor	Atmospheric Instrumentation Research, Inc.	AIR-AB-2B
power transducer	Ohio Semitronics, Inc.	W-006C
current transformer	Square D, Inc.	64R-101
data acquisition system	Zond Corp.	ADAS[4]

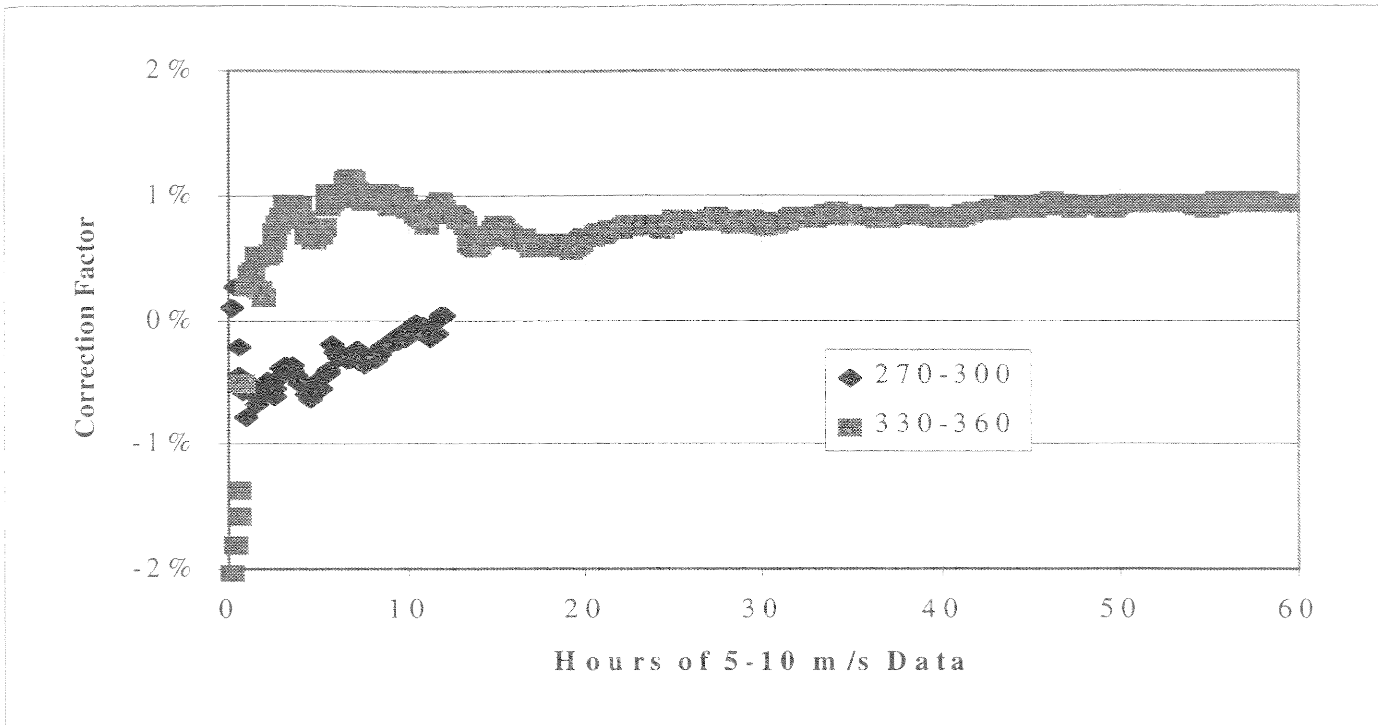

Figure 4 - Change in mean wind correction factor as a function of quantity of data

Analysis of the time series data was accomplished in several steps. First, the data were divided into 10-minute sets and mean, minimum, maximum, and standard deviation were calculated for each 10-minute set. Then the 10-minute air density average was calculated using equation (1):

$$\rho_{10min} = \frac{B_{10min}}{RT_{10min}} \qquad (1)$$

where:

ρ_{10min} = derived air density averaged over 10 minutes

T_{10min} = measured absolute air temperature averaged over 10 minutes

B_{10min} = measured air pressure averaged over 10 minutes

R = gas constant 287.05 J/kg K

The next step is to eliminate data taken when the wind is from the wrong direction. The Standard prohibits use of data when obstacles might affect wind flow at either the test turbine or at the meteorological tower. According to the Standard's guidelines, there were two obstacles that could distort wind speed measurements at Site 1.1. The turbine itself was an obstacle when its wake affected wind speed measured at the meteorological tower. In addition, a neighboring turbine (Site 1.2 on Figure 1) affects winds blowing from the south. These obstructions prohibited use of data when winds blew within the sector from 59° to 226° as shown in Figure 1.

When the site calibration is completed, the wind speed data will be adjusted by the appropriate correction factor depending upon the 10-min mean wind direction. Because the site calibration was not completed for this paper, this step was skipped.

The Standard requires that power curves be normalized to two air densities. The first is the average air density for the test site, "site air density," which is determined by averaging air density values for all allowable 10-minute data sets. In these tests, the site air density was 1.014 kg/m^3. The second is "standard air density" at sea level. As defined by the International Standards Organization[5] a standard atmosphere has a density of 1.225 kg/m^3.

The Standard specifies two methods depending upon the turbine type. For stall-regulated turbines, such as the AOC 15/50, power is normalized using Equation (2).

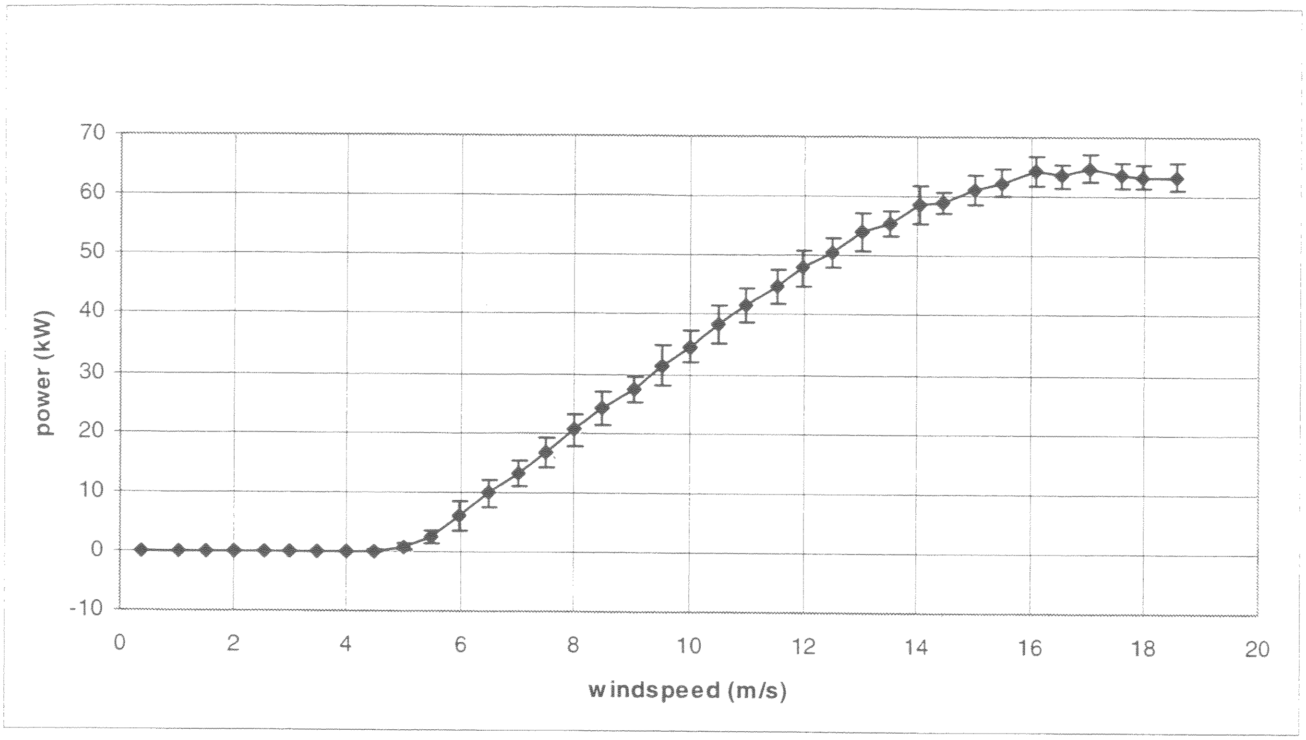

Figure 5 - Measured power curve from the AOC 15/50 at test-site-air density 1.014 kg/m³ including with combined uncertainty

$$P_n = P_{10min} * \frac{\rho_o}{\rho_{10min}} \quad (2)$$

where:

P_n = normalized power output

P_{10min} = measured power averaged over 10 minutes

ρ_o = normalizing air density, either site air density average (1.014 kg/m^3) or standard air density (1.225 kg/m^3)

ρ_{10min} = measured air density averaged over 10 minutes

For turbines with active controls, such as pitch regulation to control peak power, wind speed, not power, is normalized for air density. Although each of these methods has some shortcomings, normalization to sea-level conditions permits the comparison of power curves even though the turbines are tested under different conditions.

The Standard recommends, but does not require, determination of the power coefficient according to Equation (3).

$$C_{p,i} = \frac{P_i}{\frac{1}{2}\rho_o A V_i^3} \quad (3)$$

where:

$C_{p,i}$ = power coefficient in bin i
V_i = normalized and averaged wind speed in bin i
P_i = normalized and averaged power output in bin i
A = swept area of the turbine rotor
ρ_o = reference air density

The Standard also requires calculating the annual energy production (AEP) by applying the measured power curve to different reference wind speed frequency distributions. In Table 2, a Rayleigh distribution is used as the reference wind speed frequency distribution. The availability of the turbine is assumed to be 100%.

Table 2 - Measured AEP with Normalizing Air Density 1.014 kg/m^3

Hub Height Annual Average Wind speed m/s	AEP Measured MWh	AEP Uncertainty MWh
4	27.4	± 6.1
5	61.9	± 9.7
6	103.9	± 12.7
7	147.0	± 14.8
8	185.2	± 16.1

Uncertainty Analysis

A key element in the Standard is the requirement to estimate and report measurement uncertainty. Measurement uncertainty characterizes the range of values that can be reasonably attributed to the parameter being measured. Despite the considerable effort required to estimate the uncertainty in individual measurements and, ultimately, the power curve, the method relies heavily upon good engineering judgment.

The estimation of uncertainty used procedures and guidance contained in two documents, the Standard and the ISO guide "Guide to the Expression of Uncertainty in Measurement"[6]. Table 3 provides the list of uncertainty parameters that were considered.

Table 3 - Uncertainty parameters

Measured parameter	Uncertainty component	Type
Electric power	Variability of electric power	A
	Current transformers	B
	Power transducer	B
	Data acquisition system	B
Wind speed	Anemometer calibration	B
	Operational characteristics	B
	Mounting effects	B
	Data acquisition system	B
	Flow distortion due to terrain	B
Air temperature	Temperature sensor	B
	Radiation shielding	B
	Mounting effects	B
	Data acquisition system	B
Air pressure	Pressure sensor	B
	Mounting effects	B
	Data acquisition system	B

The ISO Guide describes two types of uncertainty. Type A uncertainty is the uncertainty associated with the statistical distribution of the measurements. Type B uncertainty is estimated by other means than the statistical analysis of series of measurements. The Guide specifies that uncertainty should be expressed in the units of the parameter being measured, not in terms of percentage.

The Standard requires consideration of only one Type A uncertainty, the uncertainty of the normalized and averaged electric power data in each bin. This parameter was calculated using Equation 4:

$$s_{p,i} = \frac{\sigma_{pi}}{\sqrt{N_i}} \tag{4}$$

where:

$s_{p,i}$ = Type A uncertainty of power in bin i

σ_{pi} = standard deviation of the normalized power data in bin I

N_i = number of 10 minute data sets in bin i

The Type B uncertainty was estimated using data provided in instrument calibrations, manufacturer's specifications, instrument mounting, and experience with properties of associated instruments. The Type B uncertainty was estimated for four measured parameters: power output, wind speed, temperature, and pressure.

The wind speed measurement uncertainty is a combination of uncertainty in anemometer calibration, operational characteristics of the anemometer, flow distortion due to mounting effects of the anemometer, flow distortion due to the terrain, and data acquisition system. The uncertainty in operational characteristics of the anemometer includes anemometer over-speeding, sensitivity to temperature and air density. In addition, the uncertainty due to operational characteristics encompasses the uncertainties from using a wind-tunnel-calibrated anemometer to measure free stream wind velocity. The uncertainty due to flow distortion caused by mounting effects includes effects from the mast. This uncertainty may be increased if the anemometer is not mounted on a tube on top of the mast. If no site calibration is done, the uncertainty in flow distortion due to the terrain is estimated to be 2 or 3%, dependent on the distance between the meteorological tower and the turbine. Otherwise, this uncertainty is estimated using site calibration data. Because the site calibration has not been completed, the uncertainty of flow distortion due to the terrain in this uncertainty analysis is estimated as 2.0% as recommended in the Standard. When the site calibration is completed, the uncertainty in flow distortion due to the terrain will reflect the uncertainty calculated from the site calibration data. Table 4 shows the uncertainty for each component and where it was obtained. Figure 6 shows that the uncertainties from anemometer calibration and flow distortion due to the terrain make up a large percentage of the wind speed uncertainty. The uncertainty in the data acquisition system that is found in the manual is found to be negligible and is not included in Figure 6.

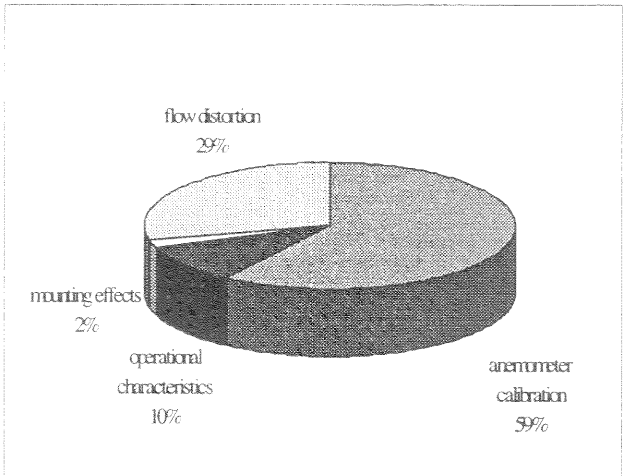

Figure 6 - Components of the wind speed uncertainty at 10 m/s

Table 4 - Wind Speed Uncertainties

Component	Uncertainty	Rationale
Anemometer	0.3 m/s	calibration
Operational characteristics	1.2%	manual
Mounting effects	0.6%	estimated
Acquisition system	< 0.1 %	previous experience
Flow distortion	2.0 %	Standard

Note: All percentages are % of average wind speed in bin.

For power output, uncertainty is a combination of uncertainties in the current transformer, power transducer, and data acquisition system. The IEC standards, IEC-185[7] and IEC-688[8], characterize and classify current transformers and power transducers, respectively. These two standards provide uncertainty limits and guidance to estimating the uncertainty for these instruments. The Standard provides guidance on combining these uncertainties for each of these instruments. Table 5 shows the uncertainty for each instrument and where the value was obtained.

Table 5 - Power Sensor Uncertainties

Component	Uncertainty	Rationale
Current transformer	2.8%	IEC-185
Power transducer	< 0.1 kW	IEC-688
Acquisition system	0.04 kW	ADAS manual

Note: All percentages are % of average power output in each bin.

The air density measurement uncertainty is a combination of the uncertainties in measuring air temperature and pressure. The temperature measurement uncertainty considers the temperature sensor calibration, imperfect radiation shielding of the temperature sensor, mounting effects of the temperature sensor, and data acquisition system. The pressure sensor uncertainty was based on the air pressure sensor calibration, mounting effects of the air pressure sensor, and data acquisition system. Table 6 shows the uncertainty for the air density components.

Table 6 - List of Air Density Uncertainties

Component	Uncertainty	Rationale
Temperature		
Temperature sensor	0.14 C	calibration
Radiation shielding	1.15 C	manual
Mounting effects	0.04 C	estimated
Acquisition system	0.36 C	ADAS manual
Pressure		
Pressure sensor	0.29 hPa	calibration
Mounting effects	0.03 hPa	estimated
Acquisition system	0.04 hPa	ADAS manual

Since these uncertainties are used to estimate the uncertainty in the power curve, there are sensitivity coefficients for wind speed, temperature, and pressure to put these uncertainties in units of power (kW). The sensitivity coefficient describes how the uncertainty of power output varies with changes in the uncertainty of wind speed, temperature, and pressure. The sensitivity coefficient is a function of power and varies from bin to bin. An example from the AOC 15/50 uncertainty analysis of sensitivity coefficients are shown in Table 7.

After the sensitivity coefficients are calculated, all the uncertainties can be incorporated into the combined Type B uncertainty. Equation (5) shows how the combined Type B uncertainty is calculated:

$$u_i = \sqrt{u_{p,i}^{2} + c_{v,i}^{2} u_{v,i}^{2} + c_{T,i}^{2} u_{T,i}^{2} + c_{B,i}^{2} u_{B,i}^{2}} \quad (5)$$

where:

u_i = combined Type B uncertainty
$u_{p,i}$ = power uncertainty
$c_{v,i}$ = wind speed sensitivity coefficient
$u_{v,i}$ = wind speed uncertainty
$c_{T,i}$ = temperature sensitivity coefficient
$u_{T,i}$ = temperature uncertainty
$c_{B,i}$ = pressure sensitivity coefficient
$u_{B,i}$ = pressure uncertainty.

Figure 7 shows the percentage of Type B uncertainties at the 10 m/s bin. The wind speed uncertainty constitutes a large percentage of the combined uncertainty at 84.6%.

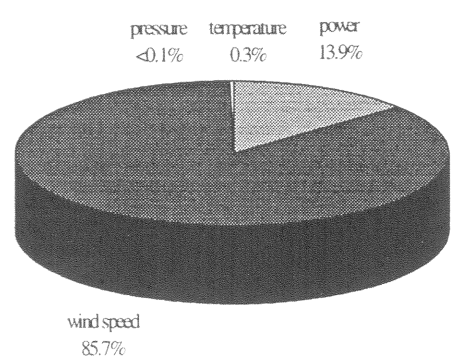

Figure 7 - Percentage of Type B uncertainties at 10 m/s

Combined uncertainty for the power curve characterizes the distribution of the power values that could be reasonable in attributing to the measured wind speed. Figure 7 shows the combined uncertainty for each bin in the measured power curve. The combined uncertainty is obtained from the combination Type A and Type B uncertainty as shown in Equation 6:

$$u_{c,i} = \sqrt{s_i^{2} + u_i^{2}} \quad (6)$$

where:

$u_{c,i}$ = combined uncertainty
s_i = combined Type A uncertainty
u_i = combined Type B uncertainty.

Table 7 - Uncertainties and Sensitivity coefficients for 10 m/s bin

Component	Uncertainty	Sensitivity Coefficient	Uncertainty kW
Combined Uncertainty	-	-	2.60
Type A	-	-	0.31
Type B	-	-	2.59
Wind Speed	0.37 m/s	6.35 kW/(m/s)	2.35
Power	0.96 kW	1.00 kW/kW	1.00
Temperature	1.21 K	0.12 kW/K	0.15
Pressure	0.29 hPa	0.04 kW/hPa	0.01

Discussion

Adoption of the new IEC testing standard was not accomplished without some difficulties. In some cases the changes from existing practices at the NWTC were minimal. In some, implementation has not yet been completed. However, the adoption of the methods described in the Standard should lead to wider acceptance of test results especially by certification and regulatory agencies. This is significant since, previously, acceptance of test results could be a significant impediment to wind turbine manufacturers and wind farm developers.

In comparison with other protocols, such as the IEA recommended practice[9] and the AWEA standard[10], the IEC standard places relatively strict requirements on instrumentation and analysis procedures. These requirements may cost more, but should lead to higher quality test results.

In particular, the Standard introduces site calibration methods to better define the terrain on wind speed measurements. In the past, such effects could be judged by some as reason to reject power performance measurements made on hilly sites. Although the procedures for site calibration are not well defined, the approach is reasonable and the results certainly reduce overall measurement error if the terrain is not very smooth. Perhaps the biggest disadvantage to the procedure is that it may lead to overconfidence in our ability to measure wind turbine performance when the surroundings are very complex such as in the midst of a wind farm.

As test engineers obtain more experience in these procedures, they will be improved. For example, our site calibration results suggest that the site correction factors will be better defined if more than 3 hours of data are obtained.

The requirement to analyze and report measurement uncertainty analysis should yield long-term benefits. Although this type of analysis has been in existence for many years, it is seldom reported in test reports. The result of this omission is the implication that the measured power curve is exact. Consideration of uncertainty will almost certainly result in better attention to the details that have the greatest impact and, eventually, to quality test results. On the contrary, those areas which have a small effect on uncertainty can by streamlined—leading to reductions in testing cost and time.

The key difficulty with the uncertainty analysis is its reliance on good engineering assumptions to define the effects of such phenomena as anemometer operational effects. While this situation cannot be improved immediately, test engineers and researchers should be working toward quantifying these judgments with supporting data. Several programs are being conducted internationally which seek to accomplish this[11,12]. In the meantime, it is important to achieve some consensus on the assumptions.

Conclusions

Although the primary purpose of the work described in this paper was to obtain practical experience with new testing methods, several important conclusions were reached:

Testing to date indicates that flow distortion due to the NWTC's terrain can affect wind speed measurements by as much as 1- 2 %. Measurement and inclusion of this effect will result in a more accurate definition of power performance characteristics.

Analysis of the site calibration data indicts the need to obtain more data than the minimum, 3 hours per sector, required by the Standard.

The uncertainty analysis indicates the power curve measurement uncertainties are caused primarily by uncertainty in wind speed measurements. This finding supports the emphasis in the standard and NWTC procedures on careful anemometer calibration, mounting, and usage.

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